BEFORE THE
PUBLIC SERVICE COMMISSION OF WISCONSIN

Joint Application of American Transmission Company LLC and Northern States Power Company–Wisconsin, as Electric Public Utilities, for Authority to Construct and Operate a New 345 kV Transmission Line from the La Crosse area, in La Crosse County, to the greater Madison area in Dane County, Wisconsin	Docket No. 5-CE-142

REVISED DIRECT TESTIMONY OF WILLIAM POWERS IN OPPOSITION TO THE APPLICATION

I. Introduction

Q. Mr. Powers, please state your name, position and business address.

A. William E. Powers, P.E., principal of Powers Engineering, 4452 Park Blvd., Suite 209, San Diego, California, 92116.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Citizen Energy Task Force, Inc. and S.O.U.L. of Wisconsin, Inc ("CETF/SOUL").

Q. Mr. Powers, please summarize your educational background and recent work experience.

A. I am a consulting energy and environmental engineer with over 30 years of experience in the fields of power plant operations and environmental engineering. I have permitted numerous peaking gas turbine, microturbine, and engine cogeneration plants, and am involved in siting of distributed solar PV projects. I began my career converting Navy and Marine Corps shore installation power plants from oil-firing to domestic waste, including woodwaste, municipal solid waste, and coal, in response to concerns over the availability of imported oil following the Arab oil embargo. I wrote "San Diego Smart Energy 2020" (2007) and "(San Francisco) Bay Area Smart Energy 2020" (2012). Both of these strategic energy plans prioritize energy efficiency, local solar power, and combined heat and power systems as a more cost-effective and efficient pathway to large reductions in greenhouse gas emissions from power generation compared to conventional utility procurement strategies. I have written articles on the strategic cost and reliability advantages of local solar over large-scale, remote, transmission-dependent renewable resources. I have a B.S. in mechanical engineering from Duke University, an M.P.H. in environmental sciences from the UNC – Chapel Hill, and am a registered professional engineer in California. My complete resume is provided as Ex.-CETF/SOUL-Powers-1.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to evaluate: 1) the expected peak load growth of Wisconsin utilities over the next decade, and 2) the feasibility and cost-effectiveness of alternatives including load management, energy efficiency, local solar, biogas, and energy storage as viable no-wires alternatives to the Applicant's proposed Badger-Coulee (B-C) 345 kV transmission line.

II. Summary and Conclusions

Q. What documents have you reviewed as part of your investigation?

A. The principal documents I have reviewed include: the March 31, 2014 and July 31, 2013 versions of ATC's Planning Analysis of the Badger-Coulee Transmission Project, 2011-2020 peak load data is from individual utility filings in the 2013 Wisconsin Strategic Energy Assessment Docket, Docket 5-ES-107, Strategic Energy Assessment - Energy 2020, We Energies and Wisconsin Public Service Company load management rate structures, evaluation of Focus On Energy 2013 energy efficiency savings performance, Geronimo Energy 2013 application to build 100 MW of solar projects in Minnesota and subsequent rulings on the application by the Minnesota Public Utilities Commission, 2014 American Wind Energy Association documents on wind capacity installation trends, Energy Information Administration forecast near- and mid-term U.S. wind capacity additions, U.S. Department of Energy evaluation of current and near-term solar cost, and the September 15, 2014 opening testimony of Michael Goggin and Amanda King-Huffman.

Q. Please summarize your findings and conclusions.

- There is no significant peak load growth forecast by ATC Wisconsin (ATCW) member utilities over the 2014-2023 study period.

- There is no significant peak load growth forecast by Dairyland Power Cooperative Wisconsin (DPCW) or Northern States Power Wisconsin (NSPW) over the 2014-2023 study period.

- Actual peak load growth in the La Crosse/Winona area is modest, less than 0.5 percent per year, if no available load management (LM) is deployed by DPCW or NSPW. If available LM had been deployed to offset peak demand, the actual demand trend would be slightly negative.

- Neither DPCW nor NSPW deployed any LM to offset their respective 2013 peak loads.

- Load management (LM) is the most cost-effective resource to offset peak demand. ATCW member utilities, DPCW, and NSPW have the potential to expand their LM capacity.

- The assumption by the Applicants of 0.5 percent per year energy efficiency savings is incorrect. Actual energy efficiency savings achieved in 2013 was 0.75 percent per year, the 2013 target for the Focus On Energy (FoE) program.

- Applicants overstate the economic benefits of wind power.

- Applicants overstate the role of transmission constraints in restricting wind development and ignores the role of market forces, including the expected end to subsidies, in limiting wind power development.

- Applicants ignore the economic competitiveness of solar power with wind power and the better match of solar output with summer peak demand.

- The Minnesota Public Utilities Commission has determined that distributed solar power is a lower cost alternative to meeting peak demand needs than a simple cycle gas turbine.
- The futures scenarios modeled by the Applicants show a substantial increase in CO_2 emissions with Badger-Coulee. Use of LM, energy efficiency, and local solar to address the need, or displace existing conventional fossil fuel generation over time, will result in a steady decrease in CO_2 emissions from power generation serving Wisconsin.

III. Legal Framework

Q. Why do you believe that a focus on non-wire alternatives is legally relevant to these proceedings?

A. Wisconsin law states an unequivocal preference for energy efficiency and clean alternatives to conventional power generation to meet the state's electric power needs:[1]

> (2) CONSERVATION POLICY. A state agency or local governmental unit shall investigate and consider the maximum conservation of energy resources as an important factor when making any major decision that would significantly affect energy usage.
>
> (3) GOALS.
>
> (a) Energy efficiency. It is the goal of the state to reduce the ratio of energy consumption to economic activity in the state.
>
> 4) PRIORITIES. In meeting energy demands, the policy of the state is that, to the extent cost‒effective and technically feasible, options be considered based on the following priorities, in the order listed:
>
> (a) Energy conservation and efficiency.
>
> (b) Noncombustible renewable energy resources.
>
> (c) Combustible renewable energy resources.
>
> (d) Nonrenewable combustible energy resources, in the order listed:
>
> 1. Natural gas.
>
> 2. Oil or coal with a sulphur content of less than 1%.
>
> 3. All other carbon‒based fuels.
>
> (5) MEETING ENERGY DEMANDS. (a) In designing all new and replacement energy projects, a state agency or local governmental unit shall rely to the greatest extent feasible on energy efficiency improvements and renewable

[1] Wis. Stat. § 1.12.

energy resources, if the energy efficiency improvements and renewable energy resources are cost–effective and technically feasible and do not have unacceptable environmental impacts.

IV. Peak Load Growth Trends

Q. Do utilities in ATCW service territory forecast no growth through 2020?

A. Yes. Based on the peak load forecast filings of the utilities that collectively represent the entirety of ATCW's load, the combined unadjusted gross peak load does not return to actual 2012 non-coincident gross peak load until sometime after 2020, if ever.[2]

Q. Did you analyze both unadjusted gross peak load as well as net peak load for each ATC member utility, as well as NSPW and DPCW?

A. Yes. I reviewed unadjusted gross peak load as well as net peak load for each utility. Unadjusted gross peak load was selected by Powers Engineering as a useful indicator of peak load growth trends as it removes the effect of varying LM dispatch practices over time, and the potential bias of changes in the amount of capacity bought or sold at peak in a given year, that are included in net peak load forecast projections. Non-coincident data was used because ATCW member utilities report their peak load, and peak load forecasts, as individual utilities. ATCW also reports its coincident system peak load.

Q. What trends did you observe in the unadjusted gross peak load forecasts?

A. The gross peak load trend is either flat or declining through 2020 on an individual utility basis. Table 1 shows the forecast gross peak load trends in each of the utilities in ATCW service territory. The combined forecast gross peak ATCW load in 2020, 12,500 MW, is less than the combined gross peak ATCW load of 12,589 MW in 2012.

Table 1. Non-coincident unadjusted gross peak load data for each utility in ATCW service territory, 2011-2020[3]

[2] Ex.-CETF/SOUL-Lanzalotta-3, Table 1, p. 7.

[3] *Id.*

Load Serving Entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
MGE	778	767	730	742	748	755	762	769	775	782
We Energies	5,645	5,737	5,458	5,461	5,542	5,601	5,664	5,687	5,706	5,742
WPSC	2,343	2,377	2,349	2,279	2,339	2,348	2,363	2,367	2,371	2,375
WI P & L	2,612	2,702	2,603	2,531	2,545	2,563	2,582	2,603	2,625	2,648
WPPI	994	1,006	973	925	929	934	939	943	948	953
Total gross non-coincident peak demand:	12,372	12,589	12,113	11,938	12,103	12,201	12,310	12,400	12,425	12,500

Q. Did you also evaluate the net peak load forecast through 2020 for each ATCW member utility?

A. Yes. Table 2 is the net load forecast through 2020 prepared by each of the utilities in ATCW service territory. The net forecast accounts for: 1) the expected amount of LM dispatched to reduce peak load, and 2) the amount of capacity purchased by the utility or committed to other users and the impact of these buy/sell transactions on the net peak load. As shown in Table 2, the combined non-coincident net peak load for the utilities in ATCW service territory is about 550 MW less in 2020, at 12,144 MW, than the actual 12,695 MW combined non-coincident net peak load reached in 2012.

Table 2. Non-coincident net peak load data for each utility in ATCW service territory, 2011-2020[4]

Load Serving Entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
MGE	778	717	680	635	641	648	655	662	668	675
We Energies	5,969	6,072	5,750	5,569	5,622	5,682	5,745	5,769	5,788	5,824
WPSC	2,371	2,384	2,361	2,262	2,281	2,294	2,344	2,347	2,351	2,354
WI P & L	2,924	3,120	2,710	2,626	2,629	2,636	2,528	2,543	2,564	2,585
WPPI	334	402	539	502	547	561	692	697	701	706

[4] *Id.*

Total non-coincident net peak demand:	12,376	12,695	12,040	11,594	11,720	11,821	11,964	12,018	12,072	12,144

Q. Did you also evaluate the gross and net peak load growth trends for non-ATCW utilities DPCW and NSPW?

A. Yes. A similar trend, especially when considering net non-coincident peak load, is also evident for the two major Wisconsin utilities not in ATCW service territory, DPCW and NSPW, that serve the La Crosse area. Table 3 shows the actual gross peak load in DPCW in 2012 was 749 MW and the forecast 2020 gross peak load is 802 MW. For NSPW, the 2011 gross peak load was 1,469 MW, while the forecast 2020 gross peak load is 1,488 MW.

Table 3. Non-coincident unadjusted gross peak load data for DPCW and NSPW, 2011-2020[5]

Load Serving Entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
DPCW	714	749	723	760	775	780	785	791	796	802
NSPW	1,469	1,421	1,361	1,400	1,426	1,443	1,463	1,472	1,479	1,488

Q. What is the net peak load growth trend in DPCW and NSPW?

A. The net growth trend for both is relatively flat. Table 4 shows historic and forecast net peak loads for DPCW and NSPW. The net peak load represents the amount of grid power the utility must supply when LM and capacity sales or purchases are accounted for. The trend is no significant net peak load growth through 2020. The net peak load in DPCW territory was 732 MW in 2012. It is forecast by DPCW to be 750 MW in 2020 (18 MW of net peak load growth over 10 years). The net peak load in NSPW service territory was 1,417 MW in 2012. It is forecast by NSPW to be 1,422 MW in 2020. This is a projected net peak load growth rate of 0.24 percent per year in DPCW territory and 0.035 percent per year[6] (5 MW of net load growth over 10 years). What is significant are use of demand

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[5] Ex.-CETF/SOUL-Powers-43; Ex.-CETF/SOUL-Powers-36.

[6] Annual rate of increase=101,422 MV/1,417 MV – 1 = 1.00035 – 1 = 0.00035 (0.035 percent per year).

response and capacity sales and purchases, which I will address more specifically later in this testimony.

Table 4. Non-coincident net peak load data for DPCW and NSPW, 2011-2020[7]

Load Serving Entity	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
DPCW	663	732	723	708	723	728	733	739	744	750
NSPW	1,417	1,369	1,309	1,283	1,361	1,378	1,398	1,407	1,414	1,422

Q. Does the actual and forecast coincident peak load reported by ATCW show no growth when compared to the Limited Growth Scenario?

A. Yes. ATCW actual and forecast coincident peak load data show no net peak load growth over time. Table 5 shows weather-normalized and actual ATCW coincident peak loads in 2007 and 2013, and the ATCW forecast peak load in 2023 in the Limited Growth scenario. As evident in Table 5, even assuming a 0.22 percent per year peak load growth in the Limited Growth Scenario, there is no significant difference between the actual ATCW peak loads recorded in 2007 and 2013 and the forecast peak demand for 2023. In other words, some peak load growth must be assumed for the ATCW peak load in 2023 to return to the actual coincident peak load the ATCW has already experienced in 2007 and 2012.

Table 5. ATCW actual and forecast peak loads, 2007, 2013, and 2023[8,9,10]

ATCW coincident peak load	2007	2013	2023 Limited Growth scenario
Weather-normalized, MW	12,888	12,788	12,801

[7] Ex.-CETF/SOUL-Powers-43; Ex.-CETF/SOUL-Powers-36.

[8] Ex.-Henn-2 (PSC Ref. # 226511), p. 26, Response No. 2.17 (citing PSC Ref. ## 226011; 218168).

[9] *Id.* at p. 30, Response No. 4.02 (citing PSC Ref. # 213034).

[10] *Id.* at p. 29, Response No. 3.01 (citing PSC Ref. # 206048).

Actual, MW	12,654	12,735	NA

The actual business-as-usual trend in ATCW service territory is no peak load growth. Even when modest peak load growth is assumed in the case of the Limited Growth scenario, there is no peak load growth from 2007 or 2013 to 2023.

V. Load Growth Projections in the Applicants Futures Scenarios

Q. Do the load growth projections in the Applicants Futures Scenarios contradict the no growth forecasts for indigenous Wisconsin load by Wisconsin utilities?

A. Yes. The Futures Scenarios analyzed in MTEP 13 modeling assume varying degrees of peak demand growth over the study period. There is no scenario with no growth or with negative growth. Three scenarios are examined: Limited Growth, Business-As-Usual, and Robust Economy.[11] The lowest peak demand growth examined is 0.22 percent per year through 2023 in the Limited Growth scenario. Business-As-Usual assumes a peak load growth of 0.81 percent per year. The Robust Growth Scenario assumes a peak demand growth rate of 1.34 percent per year. The NERC violations on the existing transmission system that would partially be addressed by Badger-Coulee (B-C), or completely addressed by the "Low Voltage - LV" alternative to Badger-Coulee, are caused by this projected load growth assumed by the Applicants over the 2014-2023 study period. Any level of load growth in the Applicants Futures Scenarios contradicts the forecasts of the utilities in ATCW service territory of no peak load growth through 2020.

Q. Does the modeling that quantified 2023 NERC violations on LV segments if B-C is not built assume a high peak demand growth rate?

A. Yes. The assumed load growth in the MTEP 13 modeling - which quantified the magnitude of the NERC violations on the existing LV segments - is very high on some LV segments, even when compared to the highest 1.34 percent per year peak load growth rate in the Robust Economy scenario. For example, assuming the LV segments with

[11] (PSC Ref. # 201972).

NERC violations in 2023 were operating at their MVA capacity rating in 2014, peak demand growth rates of up 2.8 percent per year are assumed in the MTEP 13 PROMOD modeling for the LV segments. The minimum peak load growth rates assumed in the model for ATC LV segments with 2023 NERC violations that would be addressed by B-C are shown in Table 6.[12]

Table 6. Minimum peak load growth modeled in ATC LV segments with 2023 NERC violations that would be avoided if B-C is built

Line Segment	Existing capacity (MVA)	Projected peak load in 2023 (MVA)	Delta (MVA)	Minimum peak load growth rate needed to reach projected 2023 load, 2014-2023 (%-yr)
Petenwell-ACEC Badger West-Saratoga 138 kV	81.0	94.9	13.9	1.6[13]
Council Creek-Petenwell 138 kV	191.0	220.0	29.0	1.4
Point Edwards-Sand Lake Tap 138 kV	153	157.4	4.4	0.3
Werner-Werner West 138 kV	335	342.6	7.6	0.2
Wildwood-McMillan 115 kV	115	115.4	0.4	0.03
Hillside-La Pointe Tap 69 kV	58.0	70.6	12.6	2.0
La Pointe Tap-Bloomington 69 kV	54.0	66.1	12.1	2.0
Bloomington-Glen Haven Tap 69 kV	60	62.9	2.9	0.5
Glen Haven Tap-Nelson Dewey 69 kV	53.0	61.8	8.8	1.5
Big Pond-Necedah Tap 69 kV	76	76.6	0.6	0.1
Council Creek-Douglas Tap 69 kV	68.0	81.9	13.9	1.9
Camp Douglas Tap-New Lisbon Tap 69 kV	69.0	78.6	9.6	1.3

[12] Nine of the sixteen LV segments with NERC violations that would be primarily or completely addressed by B-C are included in Table 1. These are the nine LV segments with the highest projected peak demand growth rates from among the sixteen LV segments that would be primarily or completely addressed by B-C.

[13] $Annual\ rate\ of\ increase = \sqrt[10]{94.9\ MVA/81.0\ MVA}$ – 1 = 1.01596 – 1 = 0.01596 (1.596 percent per year).

New Lisbon Tap-West Mauston Tap 69 kV	69	71.2	2.2	0.3
West Mauston Tap-Hilltop 69 kV	54.0	71.1	17.1	2.8
Hilltop-Buckhorn Tap 69 kV	58	62	4	0.7
Lincoln (LPS)-ACEC Brooks Tap 69 kV	51.0	60.6	9.6	1.7
Total magnitude of NERC violations (MVA)			148.7	

Q. What is the driver for the forecast loads leading to modeled 2023 NERC violations on the LV segments?

A. Power transfers. There is no collective, indigenous load growth projected by the utilities that are served by ATCW. As a result, ATCW forecasts no net load growth through 2023, even when assuming a peak load growth rate of 0.22 percent per year, compared to actual coincident peak loads recorded in 2007 and 2012. The entirety of the potential LV NERC violations identified in 2023 in the MTEP13 modeling is exclusively the result of overloads caused by power transiting through Wisconsin to serve loads to the east and south of the state. There would be no modeled LV system NERC violations in 2023 attributable to native load growth.

Q. Is this same driver leading to modeled 2023 NERC violations on the non-ATC LV segments?

A. Yes. This same pattern is evident in the assumed peak load growth rates for the LV segments with NERC violations in 2023 outside of ATCW that would be avoided by B-C. Table 7 shows the minimum modeled peak load growth rate for selected LV segments in this category.

Table 7. Minimum peak load growth modeled in LV segments with 2023 NERC violations outside of ATCW that are avoided if B-C is built

Line Segment	Existing capacity (MVA)	Projected peak load in 2023 (MVA)	Delta (MVA)	Min. peak load growth rate needed to reach projected 2023 load, 2014-

				2023 (%-yr)
AS King-Eau Claire 345 kV (MN/WI)	1188.5	1197.4	8.9	0.07
Mitchell County-Hazelton 345 kV (IA)	872.0	919.4	47.4	0.5[14]
Briggs Road-Mayfair Tap 161 kV	216.0	248.8	32.8	1.4
Briggs Road-LaCrosse Tap 161 kV	177.9	190.7	12.8	0.7
La Crosse-Monroe County 161 kV	298.8	307.5	8.7	0.3
Bell Center 161 kV/69 kV transformer	72	81.7	9.7	1.3
NSP Genoa-Genoa 69 kV	94.6	96.4	1.8	0.2
West Salem-Bangor 69 kV	92.4	98.1	5.7	0.6
Bangor-Rockland 69 kV	92.7	94.1	1.4	0.15
Delmar-Boyd 69 kV	71.7	74.1	2.4	0.3
Tomah Tap-Tunnel City Tap 69 kV	95	120.5	25.5	2.4
Tunnel City Tap-Timberwolf 69 kV	95	110.1	15.1	1.5
Tomah Tap-Sparta Tap 69 kV	95	123.9	28.9	2.7
Total magnitude of NERC violations (MVA)			201.1	

Q. Is magnitude of the forecast LV segment NERC violations shown in Tables 6 and 7 consistent with ATCW member utility, DPCW, and NSPW peak demand forecasts through 2020?

A. No. The peak load growth rates shown in Tables 6 and 7 far exceed the “no growth” peak load projections through 2020 prepared by ATCW member utilities, DPCW, and NSPW. No peak load growth should be the business-as-usual scenario based on actual peak load trends in the last seven years.

Q. What is the appropriate peak demand growth or decline rate to assume in light of the peak load forecasts of the ATCW member utilities?

A. The base case peak demand growth rate assumption should either be “no growth” or a negative growth rate that reflects the net peak load rate of decline shown in Table 2. By default, the only peak demand growth scenario that should be evaluated as an upper

[14] $Annual\ rate\ of\ increase = \sqrt[10]{919.4\ MVA/872.0\ MVA} - 1$

bound sensitivity case would be the minimum growth scenario among the ATC-defined Futures Scenarios, the 0.22 percent per year Limited Growth scenario.

Q. Is assuming a maximum ATCW peak load growth rate of 0.22 percent per year conservative?

A. Yes. Assuming a real ATCW peak load growth rate of 0.22 percent per year beyond actual peak loads already experienced by ATCW is conservative. As demonstrated in Table 8, a 0.22 percent per year peak load growth rate is sufficient only to return ATCW in 2023 to the coincident peak load level it reached in 2007 and 2012. A second level of conservatism in Table 8 is assuming that all LV segments showing 2023 NERC violations in the MTEP 13 modeling are operating at their MVA capacity rating in 2014 under peak load conditions and not at some level below the capacity rating.

Q. Does reducing the assumed peak load growth rate to 0.22 percent per year reduce the magnitude of the ATCW LV segment NERC violations modeled by ATC?

A. Yes. As shown in Table 8 for LV segments in ATCW territory with NERC violations in 2023 that would be avoided by construction of B-C, the magnitude of these NERC violations is substantially reduced when a peak demand growth rate of 0.22 percent per year is assumed over the 2014-2023 period. The total magnitude of NERC violations declines from 148.7 MVA to 30.9 MVA, a decline of approximately 80 percent. The peak load growth rates for LV line segments with modeled peak load growth rates less than or equal to 0.22 percent per year (see Table 6) are left unchanged in Table 8.

Table 8. Magnitude of NERC violations in LV segments in ATCW, assuming 0.22 percent per year peak load growth through 2023, that are avoided if B-C is built

Line Segment	Existing Capacity (MVA)	Projected Peak Load in 2023 (MVA)	Delta (MVA)	Load Growth Rate, 2014-2023 (%-yr)
Petenwell-ACEC Badger West-Saratoga 138 kV	81.0	82.8	1.8	0.22[15]
Council Creek-Petenwell 138 kV	191.0	195.2	4.2	0.22
Port Edwards-Sand Lake Tap 138 kV	153	156.4	3.4	0.22

[15] $Base\ MVA\ rating\ x\ annual\ rate\ of\ increase = 81.0\ MVA\ x\ (1.0022)^{10}$ = *peak load in 2023.*

Werner-Werner West 138 kV	335	342.4	7.4	0.22
Wildwood-McMillan 115 kV	115	115.4	0.4	0.03
Hillside-La Pointe Tap 69 kV	58.0	59.3	1.3	0.22
La Pointe Tap-Bloomington 69 kV	54.0	55.2	1.2	0.22
Bloomington-Glen Haven Tap 69 kV	60	61.3	1.3	0.22
Glen Haven Tap-Nelson Dewey 69 kV	53.0	54.2	1.2	0.22
Big Pond-Necedah Tap 69 kV	76	76.6	0.6	0.08
Council Creek-Douglas Tap 69 kV	68.0	69.5	1.5	0.22
Camp Douglas Tap-New Lisbon Tap 69 kV	69.0	70.5	1.5	0.22
New Lisbon Tap-West Mauston Tap 69 kV	69	70.5	1.5	0.22
West Mauston Tap-Hilltop 69 kV	54.0	55.2	1.2	0.22
Hilltop-Buckhorn Tap 69 kV	58	59.3	1.3	0.22
Lincoln (LPS)-ACEC Brooks Tap 69 kV	51.0	52.1	1.1	0.22
Total magnitude of NERC violations (MVA)			30.9	

Q. Does reducing the assumed peak load growth rate to 0.22 percent per year reduce the magnitude of the ATCW LV segment NERC violations modeled by the Applicants?

A. Yes. As shown in Table 9 for LV segments outside of ATCW territory with NERC violations in 2023 that would be avoided by construction of B-C, the magnitude of these NERC violations is substantially reduced when a peak demand growth rate of 0.22 percent per year is assumed over the 2014-2023 period. The total magnitude of NERC violations declines from 201.1 MVA to 58.3 MVA, a decline of approximately 70 percent. The peak load growth rates for LV line segments with modeled peak load growth rates less than or equal to 0.22 percent per year (see Table 7) are left unchanged in Table 9.

Table 9. Magnitude of NERC violations in LV segments outside of ATCW, assuming 0.22 percent per year peak load growth through 2023, that are avoided if B-C is built

Line Segment	Existing Capacity (MVA)	Projected Peak Load in 2023 (MVA)	Delta (MVA)	Peak Load Growth Rate, 2014-2023 (%-yr)
AS King-Eau Claire 345 kV (MN/WI)	1188.5	1197.4	8.9	0.07[16]
Mitchell County-Hazelton 345 kV (IA)	872.0	891.4	19.4	0.22[17]

[16] This is the minimum peak load growth using the 2023 peak load projected at MTEP 13 modeling for this line segment.

Briggs Road-Mayfair Tap 161 kV	216.0	220.8	4.8	0.22
Briggs Road-La Crosse Tap 161 kV	177.9	181.6	3.7	0.22
La Crosse-Monroe County 161 kV	298.8	305.5	6.7	0.22
Bell Center 161 kV/69 kV transformer	72	73.6	1.6	0.22
NSP Genoa-Genoa 69 kV	94.6	96.4	1.8	0.20
West Salem-Bangor 69 kV	92.4	94.5	2.1	0.22
Bangor-Rockland 69 kV	92.7	94.1	1.4	0.15
Delmar-Boyd 69 kV	71.7	73.3	1.6	0.22
Tomah Tap-Tunnel City Tap 69 kV	95	97.1	2.1	0.22
Tunnel City Tap-Timberwolf 69 kV	95	97.1	2.1	0.22
Tomah Tap-Sparta Tap 69 kV	95	97.1	2.1	0.22
Total magnitude of NERC violations (MVA)			58.3	

VI. There Is No Historic Net Peak Load Growth Trend In the La Crosse/Winona Area if Available LM Resources Are Consistently Deployed

Q. What does ATC assert regarding peak load growth in the La Crosse/Winona area?

A. The Applicants asserts that rapid demand growth is occurring in the La Crosse/Winona area.[18] The La Crosse/Winona area is served by NSPW and DPCW. Approximately 90 percent of the total La Crosse/Winona area peak load is NSPW load, while the remaining 10 percent is DPCW load.[19] Complicating analysis of the La Crosse/Winona area substation load data provided by the Applicants is the fact that NSPW reports the sum of non-coincident substation peak load data while DPCW reports coincident substation peak load.

Q. Are ATC representations about the peak load growth rate in the La Crosse/Winona area accurate?

[17] Base MVA rating x annual rate of increase = 872.0 MVA x $(1.0022)^{10}$ = peak load in 2023.

[18] (PSC Ref. # 204860), p. 355.

[19] Ex.-CETF/SOUL-Powers-37, p. 11.

A. No. ATC misrepresents the historic load growth over most of the last decade in the LaCrosse/Winona area by narrowing its analysis to the one period in that historical timeline when the rate of peak load growth was high. The Applicants state:[20]

> Figure 3 shows that the La Crosse area has reached a new peak each year since 2008. Additionally, between the years of 2010 and 2012 the total load has grown 3.44%, or considerably above the average load growth for the NSP and DPC control areas over the same time period (just under 1% and 1.1% respectively).

The data would have provided a substantially different result if the Applicants had gone back a few additional years in the historic record of actual peak loads.

Q. What peak load growth trend would have emerged if ATC had included 2006 actual peak load values in its analysis?

A. Had the Applicants compared non-coincident peak load in 2006 and 2011, 465 MW and 465 MW respectively, it would have concluded that there was no peak load growth in the LaCrosse/Winona area over time instead of 3.44 percent per year. Had the Applicants compared the LaCrosse/Winona area non-coincident peak load in 2006 to 2012, 465 MW and 481 MW, it would have determined that the rate of peak load growth was less than 0.5 percent per year, not 3.44 percent.[21] Had the Applicants compared LaCrosse/Winona area coincident peak load in 2006 and 2012, and not the non-coincident peak load, it may have found no difference in coincident peak load between these 2006 and 2012.

Q. What is the absolute magnitude of the La Crosse/Winona non-coincident peak load difference between 2006 and 2012?

A. Small. It is important to underscore the difference in the La Crosse/Winona area non-coincident peak load between 2006 and 2012 is only 16 MW.

Q. Did DPCW and NSPW have LM resources available to address these 16 MW?

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[20] (PSC Ref. # 204860), p. 355.

[21] Annual rate of increase=7481 MW/465 MW = 1.0048 (0.48 percent per year).

A. Yes. The 16 MW could have been addressed by available LM resources that were not utilized. In 2012, NSPW dispatched 0 MW of the 93 MW of LM available to it to reduce peak demand on its system. DPCW dispatched only 17 MW of the 52 MW of LM available to it in 2012.

Q. What percentage of the LM available to DPCW and NSPW could reasonably be assumed to be in the La Crosse/Winona area?

A. The La Crosse/Winona area represents about 30 percent of NSPW's peak load.[22] It represents about 7 percent of DPCW's peak load.[23] Assuming LM is evenly distributed through the service territories of both utilities, NSPW could have dispatched about 27.9 MW of LM to reduce the La Crosse/Winona area gross peak load in 2012,[24] and DPCW could have dispatched about 2.5 MW.[25] There was about 30 MW of unused LM available between NSPW and DPCW to address the 2012 La Crosse/Winona area peak load. Had these LM resources been deployed in 2012, the La Crosse/Winona area would have shown a slight decline trend in non-coincident peak load between 2006 and 2012, from 465 MW to 451 MW.[26] This is equivalent to a peak demand decline rate of -0.51 percent per year.[27]

Q. Would the La Crosse/Winona area 2013 peak load of 490 MW have occurred if all available LM had been deployed to meet the peak?

A. No. Even the 2013 non-coincident peak load in the La Crosse/Winona area would have been lower than the 2006 non-coincident peak load of 465 MW if available NSPW and

22 NSPW gross peak load 2012 = 1,421 MW. NSPW La Crosse/Winona non-coincident peak load 2012 = 427 MW. Therefore, La Crosse/Winona area is about 30 percent (427 MW/1,421 MW) of NSPW net peak load.

23 DPCW coincident gross peak load 2012 = 749 MW. DPCW La Crosse/Winona coincident peak load 2012 = 53.9 MW. Therefore, La Crosse/Winona area is about 7.2 percent (53.9 MW/749 MW) of DPCW net peak load.

24 93 MW × 0.30 = 27.9 MW.

25 (52 MW – 17 MW) × 0.072 = 2.5 MW.

26 2006 non-coincident peak load = 465 MW. 2012 non-coincident peak load adjusted for 30 MW of LM dispatch = 481 MW – 30 MW = 451 MW.

27 Annual rate of increase $= \sqrt[6]{451\ MW/465\ MW}$ – 1 = -0.0051 (-0.51 percent per year).

DPCW LM resources had been deployed to reduce the peak.[28] Table 10 shows the LM resources available to NSPW and DPCW in 2013, total peak loads in NSPW and DPCW and the subset of NSPW and DPCW peak loads in the La Crosse/Winona area, the proportionate amount of LM available in the La Crosse/Winona area, and the net peak load that would have occurred if this available LM been deployed to reduce the peak load. Net peak load in 2013 would have been 458 MW, 7 MW less than the 2006 peak load of 465 MW. Under this scenario, the peak demand decline rate in the La Crosse/Winona area would be -0.22 percent per year between 2006 and 2013.[29]

Table 10. Effect of deploying available LM resources on 2013 La Crosse/Winona Area peak load

Utility	Total gross coincident peak load, 2013 (MW)	Available LM resources, 2013 (MW)	Amount LM used in 2013 (MW)	La Crosse/ Winona area gross non-coincident peak load, 2013 (MW)	Proportionate LM available in La Crosse/ Winona, 2013 (MW)	Net non-coincident peak load if available LM deployed, 2013 (MW)
NSPW	1,361	86	0	436	28	408
DPCW	723	52	0	54[30]	4	50
Net non-coincident La Crosse/Winona area 2013 peak load (MW):						458

In contrast to the no net load growth reality, NSPW witness Huffman states:[31]

> To estimate future potential loads, we analyzed a range of growth assumptions using the non-coincident peak of 481MW in 2012 as the base year. NSPW calculated total area load in the post 2020 timeframe based on several growth rates, 1%, 1.24%, 2%, and 3.44%.

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[28] This assumes that LM resources are uniformly distributed throughout NSPW and DPCW services territories.

[29] Annual rate of decrease $= \sqrt[7]{458\ MW/465\ MW} - 1 = -0.0022$ (-0.22 percent per year).

[30] 53.9 MW is the DPCW 2011 gross coincident peak load in the La Crosse/Winona area. This value is used as the default 2013 DPCW gross coincident peak load in the La Crosse/Winona area.

[31] Direct-Applicants-King-Huffman (PSC Ref. # 218099), pp. 11–12.

Based on forecasts using the 2012 peak, a new 345 kV transmission source could be needed as soon as the 2026 timeframe depending on growth rate (if load grows at a rate over 3% annually) or after 2050 (if load grows at a rate below 1.24% annually).

The 2013 non-coincident peak load for La Crosse/Winona Study Area substations reached a new peak of 490 MW was compared to 481 MW from 2012, 465 MW from 2011, and 451 for 2010. Average load growth from 2010-2013 is 2.79%.

Q. **Has NSPW evaluated any lower voltage alternatives for meeting load levels above 750 MWin the La Crosse/Winona Study Area?**

A. The proposed Badger Coulee Project connection at Briggs Road Substation can meet load serving needs for decades and therefore NSPW has not analyzed potential alternatives to meet the same need.

There is no load growth trend in the La Crosse/Winona area, especially if NSPW utilizes the LM resources available to it, and definitely no load growth approaching a rate of 1.24 percent per year. Therefore there is no need prior to 2050, according to NSPW projections, for B-C to address reliability needs in the La Crosse/Winona area. The failure of NSPW to look at any options to B-C to meet load growth, if load growth were occurring, also conflicts with state law that establishes clear preference for clean no-wires alternatives.

Q. The Applicants imply that frac sand mining is a significant reason for peak load increases in the La Crosse/Winona area. Is this correct?

A. No. NSPW states that there are 24 frac sand mining operations in NSPW territory with a total load of 36.5 MW.[32] NSPW has an annual peak load of approximately 1,400 MW. About 30 percent of that load is in the La Crosse/Winona area. Assuming an even distribution of frac sand mining load in NSPW territory, about 11 MW of NSPW frac

[32] Ex.-Henn-2 (PSC Ref. # 226511), p. 32, Response No. 5.02 (citing PSC Ref. # 213082).

sand mining load would be located in the La Crosse/Winona area.[33] That is only 2 to 3 percent of NSPW's peak load, about 436 MW in 2013, in the La Crosse/Winona area. Also, NSPW acknowledges that frac sand mining load is already included in its load forecast.[34]

VII. LM Resources Are Being Added at a Composite Rate of 1.5 Percent Per Year by Utilities in ATCW Member Utilities

Q. Do all ATCW member utilities have LM programs to reduce peak load?

A. Yes. All of ATCW member utilities have LM programs available to reduce gross peak load. With the exception of NSPW, all of these utilities assume maximum deployment of available LM resources in their peak load forecasts. Table 11 summarizes the amount of LM the utilities in ATCW forecast had available in 2013, the amount of these resources actually deployed in 2013, and the forecast amount of LM resources available to meet peak demand in 2020. However, five of the seven utilities in ATCW territory deployed no LM to reduce the 2013 peak load.

Table 11. Amount of LM (LM) the ATCW member utilities and DPCW/NSPW forecast will be deployed to meet gross peak demand through 2020[35]

Utility	LM available to meet peak load, 2013 (MW)	LM deployed to meet peak load, 2013 (MW)	Projected LM available to meet peak load, 2020 (MW)	Projected noncoincident gross peak load, 2020 (MW)	LM as percentage of gross peak load, 2020 (%)
DPCW	52	0	52	802	6.5
NSPW	86	0	87	1,488	5.9
MGE	57	0	57	782	7.3
We Energies	157	0	157	5,742	2.7
WPSC	214	214	282	2,375	11.9

33 0.30 × 36.5 MW = 11.0 MW.

34 *Id*.

35 Exs.-CETF/SOUL-Powers-38–41.

WPL	138	138	148	2,648	5.6
WPPI	47	0	47	953	4.9
Total:	751	352	830	14,790	

Q. Did ATCW member utilities and DCPW/NSPW use all the LM available to them to reduce the 2013 peak load?

A. No. Collectively the utilities in ATCW territory: 1) used less than half of the LM assets available to them, 352 MW of 751 MW total, to address the actual 2013 peak load.

Q. Do the ATCW member utilities and DCPW/NSPW forecast an increase in LM assets over time?

A. Yes. The ATCW member utilities and DCPW/NSPW forecast a LM growth rate of about 1.4 percent per year,[36] from 751 MW to 830 MW, from 2014 through 2020, which equates to about 11 percent for the six-year period. One utility, WPSC, is increasing LM resources at an equivalent rate of 4 percent per year in the 2014-2020 timeframe.[37]

Q. What ATCW member utility has the highest forecast use of LM to reduce peak load in 2020?

A. WPSC. WPSC projects that it will reduce 11.9 percent of its gross peak load in 2020 using LM resources. These LM resources are presumptively cost-effective given they are an integral part of the WPSC resource plan.

Q. What would be the impact on ATCW and DCPW/NSPW peak demand if all ATCW member utilities and DCPW/NSPW reduced 11.9 percent of their 2020 forecast peak load with LM?

A. It is reasonable to assume that, if WPSC can cost-effectively meet 11.9 percent of its gross peak load in 2020 using LM resources, the other utilities in ATCW territory can also cost-effectively meet 11.9 percent of their gross peak loads in 2020 with LM. Assuming for sake of argument that 11.9 percent of gross peak load represents an upper

36 Annual rate of increase $= \sqrt[7]{830\,MW/751\,MW} - 1 = 0.0144$ (1.44 percent per year).

37 Annual rate of increase $= \sqrt[7]{282\,MW/214\,MW} - 1 = 0.0402$ (4.02 percent per year).

bound of cost-effective LM resource percentage for utilities in ATCW territory, and all utilities in ATCW, and DCPW/NSPW reduce the gross 2020 peak load by 11.9 percent using LM, an additional 950 MW of peak load reduction would be achieved with LM in 2020.[38]

Q. Have the ATCW member utilities and DCPW/NSPW clarified their LM deployment strategies for the 2014-2020 period?

A. Yes. All but one of the ATCW member utilities have indicated in their current *Strategic Energy Assessment - Energy 2020* filings with PSC of Wisconsin that they will deploy100 percent of LM resources available to them to reduce peak load in the 2014-2020 period.[39] NSPW will deploy 76 percent of available LM resources.[40]

Q. Do the Applicants address the potential of LM to reduce peak load in its application to construct B-C?

A. No. The Applicant's application for B-C gives the impression that the utilities in the Applicant's service territory only deploy LM resources to meet emergency conditions, and that no increase in LM resources is likely to occur in the foreseeable future. The Applicant's state:

> ATC does not offer LM programs to retail customers nor does it have the ability to curtail retail load (except through actions of load-serving entities under emergency conditions). Moreover, under current law, as long as Wisconsin utilities are making their required contributions to the FoE program, they cannot be required to offer additional energy efficiency and LM programs.

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38 (12,500 MW × 0.119) – 809 MW = 951 MW.

39 Exs.-CETF/SOUL-Powers-38–41.

40 Total LM available = 86 MW. LM deployed = 65 MW. Percentage deployed = 65 MW/86 MW = 0.76 (76 percent).

In fact, as shown in Table 11, the member utilities in ATCW territory forecast the dispatch of 100 percent of their available LM resources to reduce peak load through 2020. This is a predictable planned action, not an emergency response.

VIII. Utility LM Programs Are the Least-Cost Alternative to Transmission Construction to Address Modeled NERC Violations

Q. What is the cost of LM?

A. I reviewed the LM pricing of two utilities, We Energies and WPSC. We Energies explains the economics of its LM program, Power Market Incentives™, in the following manner:[41]

> We Energies pays large commercial and industrial customers for voluntarily reducing electric load when the wholesale spot market spikes. The program is open to customers who can reduce at least 500 kilowatts (kW) of load quickly in response to market conditions.
>
> Under a special year-long contract, you agree to reduce your electric load for a mutually agreeable price, with these conditions:
>
> Energy buy-back offers can be made at any time during the year. A minimum commitment of 500 kW is required. You decide on a case-by-case basis how much load you want to drop. You are subject to penalty only if you don't drop what you promise.

Q. Using the We Energies example, what is the cost of LM?

A. The example given provides an approximation of the cost per MW of load reduced, and the economic penalty imposed if the agreed-upon load is not reduced when instructed by We Energies:[42]

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41 Ex.-CETF/SOUL-Powers-2, p.1.

42 *Id*.

If you enroll 500 kW at a bid price of $1/kwh and participate for 8 hours during a buy-back period, your credit will be:

500 kW x $1/kWh x 8 hours = $4,000

If you do not meet your load reduction commitment, you will pay the actual cost of replacement power for the difference between your actual kWh reduction and your committed kWh.

Q. What is the cost to reduce 1 MW of load with the We Energies LM pricing?

A. At $1/kWh, the cost to reduce load 1 MW would be $1/kWh x 1,000 kW/MW =$1,000/MW. The cost to shed 100 MW for one hour would be: $1,000/MWh x 100 MW = $100,000/hr. If an average of 100 MW had to be reduced for 10 hours during the summer peak season, the total cost would be $1,000/MWh × 100 MW × 40 hr/yr = $4,000,000/yr. Assuming 40 hours per year of this level of load reduction is sufficient to meet the annual peak LM needs of the utility, the equivalent "capacity charge," the cost to have this capacity available when needed, would be: ($4,000,000-yr) ÷ 100,000 kW = $40/kW-yr.

Q. According to Table 11, WPSC has the most aggressive LM program among the ATCW member utilities. What is the cost of LM at a WPSC?

A. The cost per MW of LM under the WPSC large commercial and industrial interruptible rate, for customers who have a minimum interruptible demand of 200 kW or more, is approximately $50/kW-yr.[43] WSPC can deploy the LM under contract to meet peak demand or for economic reasons.[44]

[43] Ex.-CETF/SOUL-Powers-3, p. 1. Participating customers get a credit of $6.301 off their monthly demand change for a minimum of eight months in which at least 200 kW can shed up to a limit of 600 hours per year of total load shedding. 1 MW (1,000 kW) LM cost example under WPSC tariff: $6.301/kW x 1,000 kW-month x 8 months = $50.41/kW-yr.

[44] *Id*. at Cp-I2.5. Customers shall be subject to two types of interruptions - Emergency and Economic. Emergency interruptions may be declared to reduce load to maintain the reliability of power system. Economic interruptions may be declared during times in which the price of electricity in the regional market significantly exceeds the cost of operating typical Company peaking generation.

Q. How does energy efficiency compare on cost to LM to reduce load?

A. Energy efficiency measures, based on the performance of FoE in 2013, have a capacity value of $114.30/kW-yr.[45] Energy efficiency measures concurrently offset large amounts of grid power purchases at a low avoided cost of approximately $0.05/kWh and eliminate 0.83 tons of CO_2 emissions per MWh of displaced grid power.[46]

Q. How does the capacity cost of a simple cycle gas turbine compare to LM for peak load reduction?

A. The capacity cost of a new peaking gas turbine power plant to provide 100 MW of capacity to meet the same need would be as much as $286.34/kW-yr. [47] A peaking gas turbine power plant does not offset grid power purchases.

Q. How does the capacity cost of distributed solar compare to LM for peak load reduction?

A. Distributed solar PV located at substations, assuming a single-axis tracking solar array with a capacity factor at the peak hour of 71 percent, has a capacity value of $$228/kW-yr to $275/kW-yr.[48]

Q. How does the capacity cost of wind power compare to LM for peak load reduction?

A. The capacity factor of wind energy during summer peak demand hours is low at 14.1 percent. As a result the cost of wind energy as a capacity resource to offset the summer peak is high at $2,078/kW-yr.[49]

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[45] Ex.-CETF/SOUL-Powers-4.

[46] *Id*. Tables 22 and 23, pp. 54-55, CY 2013 data.

[47] Ex.-CETF/SOUL-Powers-5, p. 30. Denial of the Distributed Solar Energy Proposal would prevent Xcel from meeting its peak capacity needs as identified by the Commission, which could potentially lead to blackouts or brownouts across its system. In addition, Xcel Energy may fail to meet its requirements as a member of MISO's Reserve Sharing Pool, which could cause the Company to incur a Capacity Deficiency Charge from MISO in an amount that could exceed $268,000/MW-year.[13] footnote 13: The MISO Capacity Deficiency Charge is 2.748 times the Cost of New Entry (CONE). CONE represents the cost of a new simple cycle combustion turbine. For the planning year beginning June 1, 2013, the Capacity Deficiency Charge is 2.748 x $97,650 = $268,342.20 /MW-year.

[48] See Section XII for calculations.

Q. Is LM the lowest cost alternative for reducing peak load?

A. Yes. LM is a substantially more cost-effective strategy than energy efficiency, solar PV, new peaking gas turbines, or wind power to reduce peak load. With the possible exception of WPSC, utilities in ATCW territory can add substantial amounts of cost-effective LM to address any incremental native load growth in the 2014-2023 timeframe.

IX. Effectiveness of the FoE Energy Efficiency Program Is Underestimated By Applicants

Q. Does Applicants underestimate the effectiveness of FoE energy savings in its application?

A. Yes. The actual rate of energy efficiency savings is substantially higher in Wisconsin than assumed by the Applicants in the application to construct B-C. The Applicants assume that utility energy efficiency program spending in Wisconsin, specifically in the context of the FoE energy efficiency program, will reduce both peak load and electricity consumption at a static level of 0.5 percent per year during the forecast period.[50] The FOE program target for 2011-2013 is 0.75 percent per year.[51]

Q. How do the FoE energy efficiency savings targets compare to targets in other states?

A. The Wisconsin energy efficiency savings target fall into the mid-range among the fifty states. Massachusetts leads the nation with electric efficiency savings targets that ramp up

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49 $293/kW-yr ÷ 0.141 = $2,078/kW-yr. See p. 32 for the calculations supporting the $293/kW-yr value for wind power.

50 Ex.-CETF/SOUL-Powers-6, pp. 103-104. In the most recent year for which data is available (2012), FoE reported net savings of 66.8 MW and 461 GWh. This represents approximately 0.5 percent of Wisconsin's total electric load. Thus, the net impacts of the FoE programs are decreasing the electricity growth rate in Wisconsin by approximately 0.5 percent compared to what would be expected in the absence of the program.

51 Ex.-CETF/SOUL-Powers-7. "Shortly after the EERS was approved by the Joint Finance Committee of the state legislature, the state limited funding to Focus on Energy to 1.2% of revenues, which resulted in a major reduction in energy efficiency goals. The goals are now approximately 0.75% of sales in 2011, 2012, and 2013 for electricity and 0.5% of sales for natural gas over the same time-frame."

from 2.5 percent to 2.6 percent from 2013 to 2015.[52] Minnesota is tenth in the nation with a savings target of 1.5 percent.[53] Wisconsin is seventeenth with its savings target of 0.75 percent.[54]

Q. What is the source of the Applicants assumption that the FoE will achieve only 0.5 percent per year energy efficiency savings over the 2014-2023study period?

A. This assumption is based on the performance of the FoE program in 2012. Applicants state:[55]

The Focus on Energy program maintains relatively stable goals and anticipated impacts for 2013 and beyond, compared to 2012. Therefore, future energy efficiency impacts are expected to remain at the 2012 level each year into the foreseeable future, barring substantial changes in funding levels, goals, or program effectiveness.

In fact, the FoE program ramped-up steadily over the three-year 2011 through 2013 period. The program effectiveness increased substantially in 2013 relative to 2012. Wisconsin was recognized in 2014 by the American Council for an Energy-Efficient Economy (ACEEE) as one of handful of "most improved" states due to the increase in energy efficiency savings achieved by FoE from 2012 to 2013.[56] Figure 1 shows the gross and net peak energy efficiency savings achieved by the FoE program in the 2011-2013 period.

[52] Ex.-CETF/SOUL-Powers-8.

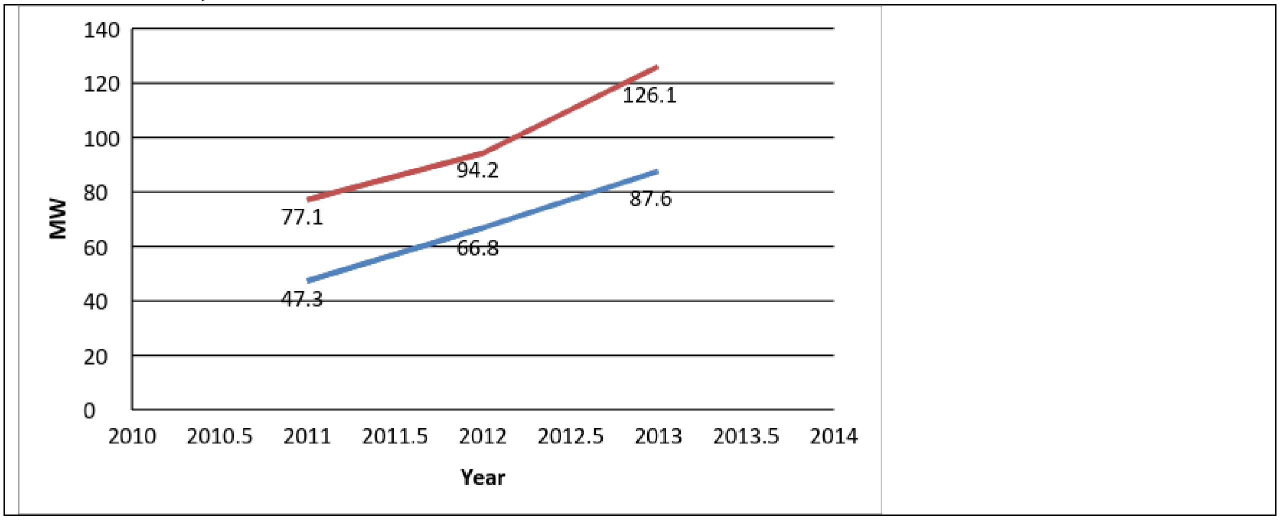
[53] Ex.-CETF/SOUL-Powers-9.

[54] Ex.-CETF/SOUL-Powers-7.

[55] PSC Ref. # 188419, pp. 258–259.

[56] Ex.-CETF/SOUL-Powers-10, p. 2. "Wisconsin bounced back in this year's State Scorecard after a shift in efficiency administrators had caused a temporary drop in savings. The state is once again realizing consistent levels of electricity and natural gas savings."

Figure 1. Gross (red) and net (blue) peak energy efficiency reductions by Wisconsin utilities, 2011-2013[57]



Q. Do the Applicants recognize that the historic performance of the FoE program has not been static over time?

A. The Applicants acknowledges that sub-par FoE performance in 2011 was in part due to the transition to a new program administrator.[58] Figure 1 makes clear that the FoE program had not realized its full potential in 2012 either.

Q. How did FoE perform in 2013?

A. Net and gross energy FoE energy efficiency savings in 2013, at 87.6 MW and 126.1 MW respectively, were approximately 0.61 percent (net) and 0.87 percent (gross) of Wisconsin's peak load.[59]

Q. Did the non-FoE energy efficiency savings rate also increase between 2012 and 2013?

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57 Ex.-CETF/SOUL-Powers-4, p. 3.

58 PSC Ref. # 188419, p. 257. "The decreased impact (of FoE) in 2011 is partially attributable to a transition period to a new program administrator, and may not be reflective of future impact levels."

59 Ex.-CETF/SOUL-Lanzalotta-3, p. 7. Wisconsin's non-coincident peak demand in 2013 reached 14,420 MW. The "net" verified MW savings of 87.6 MW represents 0.61 percent of 2013 peak demand, while the "gross" verified MW savings of 126.1 MW represents 0.87 percent of 2013 peak demand.

A. Yes. Non-FoE energy savings increased from 27.4 MW to 38.5 MW between 2012 and 2013, a 11.1 MW increase. Non-FoE energy efficiency savings result from, for example, increasingly stringent federal appliance standards that will happen with or without the FoE program. As Table 1 shows, the non-FoE rate of energy efficiency savings is increasing and needs to be factored-in to the load reduction impact of energy efficiency measures used in the Applicant's load forecasts.

Q. What was the total net 2013 energy efficiency savings rate when the increase in non-FoE energy efficiency savings is added to the FoE savings?

A. The total net energy efficiency savings for 2013, compared to the business-as-usual 2012 base case, was 0.61 percent per year (FoE net savings) + 0.08 percent per year (increase in non-FoE savings between 2012 and 2013). This is a net savings of 0.69 percent per year.

Q. Is it appropriate for the Applicants to assume 2012 FoE performance levels when the program performed to its substantially higher target level in 2013?

A. No. The Applicants erroneously uses the 2012 net FOE program savings of 66.8 MW and gross savings of 95.4 MW as the basis for assuming the FoE program load reduction is approximately 0.5 percent of Wisconsin's coincident peak load.[60] The Applicants also erroneously assumed this 2012 level of energy efficiency savings would remain constant throughout the forecast period.

Q. What FoE energy efficiency savings performance level should be assumed by the Applicants?

A. A 0.7 percent per year peak load reduction achieved by energy efficiency should be used by the Applicants in peak load forecast modeling for the 2014-2023 study period, based on the 2013 FoE program year results. The 0.7 percent per year energy efficiency savings

[60] PSC Ref. # 188419 p. 258. "As stated in the 2012 Wisconsin Strategic Energy Assessment, Wisconsin's non-coincident peak demand in July 2012 was 15,062 MW (p. 8), influenced by an extremely hot weather pattern. The "net" verified MW savings of 66.8 MW represents 0.44% of 2012 peak demand, while the "gross" verified MW savings of 95.4 MW represents 0.63% of 2012 peak demand."

rate would account for accelerating FoE net energy efficiency savings and accelerating non-FoE energy efficiency savings realized between 2012 and 2013.

Q. Can the incremental greenhouse gas reduction benefits of an additional 0.2 percent per year of energy efficiency savings be calculated?

A. Yes. The incremental 0.2 percent per year of energy efficiency savings represents a significant amount of avoided CO_2 emissions. The net savings of the FoE program in 2013 was 619,418 MWh.[61] One third of this amount, the incremental 0.2 percent per year of energy efficiency savings not accounted for by the Applicants, represents approximately 170,000 tons per year of avoided CO_2 emissions.[62]

Q. What is the avoided cost in $/kWh of energy efficiency savings?

A. The avoided cost of these 2013 energy efficiency savings was an average of approximately $0.049/kWh over the 15-year forecast period.[63] In contrast, the average cost of Wisconsin wind power is higher at $0.053/kWh.[64]

Q. What effect would an additional 0.2 percent per year in energy efficiency savings have on the sensitivity peak demand growth case that assumes a real peak demand growth rate of 0.22 percent per year?

A. Assuming a 0.7 percent per year energy efficiency peak load reduction, instead of the 0.5 percent per year assumed by the Applicants, would reduce net peak load growth by 0.2 percent per year relative to the base case energy efficiency assumption used by the

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[61] Ex.-CETF/SOUL-Powers-4, p. 3. The net FoE energy efficiency savings in 2013 was 0.61 percent per year. Therefore, each 0.1 percent per year increment in energy efficiency savings represents about 100,000,000 kWh in net savings [(0.1/0.61) × 619,418,427 kWh] = 101,544,004 kWh).

[62] *Id.*, p. 55, Table 23, (CO_2 emission factor = 0.83 tons per MWh). A 0.2 percent per year increase in energy efficiency savings equals a savings of approximately 200,000,000 kWh per year (200,000 MWh per year). Therefore, CO_2 avoided by incremental 0.2 percent per year energy efficiency savings = (200,000 MWh/yr) × 0.83 tons CO_2/MWh) = 166,000 tons/yr CO_2 avoided.

[63] *Id.*, Table 22, p. 54. "Footnote 1: CY 2012and CY 2013 cost-effectiveness analyses used a time series that grows from 0.0379 to 0.0561 ($/kWh) over 15 years in the forecast model."

[64] (PSC Ref. # 224567), p. 18. Average cost of wind power PPAs in Great Lakes region = $53/MWh.

Applicants. This would convert the 0.22 percent per year Limited Growth scenario to a near no growth trend of 0.02 percent per year.[65]

Q. Can Wisconsin increase the rate of energy efficiency savings if it chooses to do so?

A. Yes. The Energy Center of Wisconsin has identified annual energy savings potential equivalent to 1.6 percent of both total electricity sales and peak demand, and 1.0 percent of natural gas sales.[66] The cumulative efficiency savings impact from 2012 through 2018, if savings rates continued (at the target levels) would be equivalent to 13 percent of total electricity sales and 12.9 percent of peak demand. This level of additional energy efficiency savings would add 7,000 to 9,000 Wisconsin-based jobs.

X. Economic Benefit of Wind Power Is Overstated

Q. What is the primary economic reason given by the Applicants for building B-C?

A. Low-cost wind power. The Applicants state the primary economic reason for the B-C project is to move low-cost wind power from Iowa and Minnesota to meet RPS obligations in Wisconsin and states further east. The fundamental argument advanced for B-C is that there is a tremendous amount of wind power is in the development queue in these low-cost wind power states, but lack of sufficient transmission capacity, which B-C is intended to remedy, will prevent the Applicants from realizing the Renewable Investment Benefits that access to these low-cost wind resources would provide.[67, 68]

Q. Mr. Goggin implies that amount of wind power with MISO interconnection requests represents the amount of wind power that will be built if sufficient transmission is available. Is this a realistic perspective on the MISO interconnection request process?

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65 -0.20 percent per year + 0.22 percent per year = +0.02 percent per year.

66 Ex.-CETF/SOUL-Powers-11, p. 7.

67 *Id.*, p. 17.

68 (PSC Ref. # 224567), pp. 17, 24, 28.

A. No.

Q. What percentage of MISO interconnection requests have historically resulted in operational capacity?

A. About 11 percent.[69]

Q. Do the differences in wind capacity factor across the Midwest explain the large difference in wind contract prices described by Mr. Goggin?

A. No. The comparative cost of wind power presented in testimony is misleading. The cost of Great Lakes region wind power, which includes Wisconsin, is identified as $53/MWh at an average capacity factor of 0.30 to 0.345.[70] The wind power capacity factor is identified as 0.36 for Iowa and Minnesota and 0.38 for North Dakota and South Dakota.[71] These four states are part of what is known as the "Interior" region of the western MISO control area.[72] The cost of wind power contracts is reported to be $22/kWh to $27/kWh in the Interior region. The reason advanced for wind power contract prices that are less than half the contract price in the Great Lakes region is the higher capacity factor in the Interior region. The ATC Planning Analysis states:[73]

> MISO calculated three year average wind capacity factors using National Renewable Energy Lab (NREL) wind data. The values are 30.0, 36.3, and 37.8 percent for Wisconsin, Minnesota and Iowa, respectively. For the "outside" wind, an average of the Minnesota and Iowa capacity factors was used in the RIB calculation, i.e. 37.0 percent.

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69 Ex.-CETF/SOUL-Powers-12, p. 2. Since the beginning of the queue process in 1995, MISO and its Transmission Owners have received approximately 1300 interconnection requests, 256,000 MW. Among them, 28,236 MW obtained commercial operation (11.0%).

70 Revised CPCN Application, Clean Version (PSC Ref. # 204860) (as cited in Ex.-Applicants-Henn-1 (PSC Ref. # 226510), p. 2).

71 *Id*.

72 *Id*.

73 Revised CPCN Application, Clean Version (PSC Ref. # 204860) (as cited in Ex.-Applicants-Henn-1 (PSC Ref. # 226510), p. 2)..

With this guideline the wind power contract price in Iowa and Minnesota can be calculated if the wind contract price in Wisconsin is known. That contract price is \$53/kWh. The average wind power contract price in Iowa and Minnesota should be: \$53/MWh × (0.30/0.37) = \$43/MWh. Yet the wind industry is testifying in this proceeding that the contract prices in Iowa and Minnesota are in the range of \$22/MWh to \$27/MWh. This is \$16/MWh to \$21/MWh less than can be justified on differences in wind capacity factor between Wisconsin and Iowa/Minnesota. The subsidies behind these discounted wind power contract prices are not explained.

Q. Is it reasonable to assure in 2014 that subsidies for wind power will be available beyond 2015?

A. No. There is no guarantee that there will be any government subsidies available for wind power in 2016 or in 2023. As a result, it is necessary to directly calculate the unsubsidized cost of wind generation in Iowa and Minnesota to determine what the cost of wind power may be in 2023.

Q. What is the unsubsidized cost of wind power assuming the Applicants wind power capital cost and the wind power capacity factor for Iowa?

A. ATC identifies the 2018 capital cost of wind power in the Limited Growth scenario of \$2,688/kW.[74] The Energy Information Administration identifies a fixed O&M cost for onshore wind projects of \$39.55/kW-yr.[75] The total annual cost of a 100 MW wind project with these cost assumptions would be \$293/kW-yr, or \$29.3 million/yr.[76] At a capacity factor of 0.37, a 100 MW wind project will generate 324,120 MWh/yr.[77]

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[74] (REDACTED COPY) Application Appendix D, Exhibits 1 and 2 Updated (PSC Ref. # 204739), p. 9 (as cited in Ex.-Applicants-Henn-1 (PSC Ref. # 226510), p. 2). The capital cost for wind capacity (in 2018 dollars) used in the Renewable Investment Benefit (RIB) calculation ranges from \$2,688/kilowatt (kW) for slow growth to \$3,360/kW for robust economy.

[75] Ex.-CETF/SOUL-Powers-13, p. 6.

[76] At a finance rate of 7 percent interest over 20 years (0.0944/yr cost recovery factor), the annualized capital cost of a 100 MW (100,00 kW) wind project would be: \$2,688/kW x 100,000 kW x 0.0944 = \$25,374,770/yr. This equals a capacity cost of: \$25,374,770/yr ÷ 100,000 kW = \$253.75/kW-yr. The annual cost of the wind project would be: \$253.75/kW-yr + \$39.55/kW-yr = \$293.30/kW-yr.

[77] 100 MW × 8,760 hr/yr × 0.37 = 324,120 MWh/yr.

Therefore, the break-even unsubsidized power purchase wind price in 2018 would be: $29.3 million/yr ÷ 324,120 MWh/yr = $90.40/MWh.

XI. The Future Growth of Wind Power in the Upper Midwest Is Uncertain, Whether or Not B-C Is Built

Q. What is the U.S. Department of Energy (DOE) perspective on the prospects for new wind power capacity additions in the near- and mid-term?

A. DOE describes the uncertain future of wind power development in the U.S. in the following manner.[78]

> The meager 1,087 MW of wind capacity additions in 2013 (nationwide) was below all forecasts presented in last year's edition of the *Wind Technologies Market Report*. A key factor driving this outcome was the limited motivation for projects to achieve commercial operations by year-end 2013 as a result of a late extension of the PTC in January 2013 that also altered PTC (Production Tax Credit)-eligibility guidelines to only require construction to have begun by the end of that year.
>
> Because federal tax incentives are available for projects that initiated construction by the end of 2013, significant new builds are anticipated in 2014 and 2015 as those projects are commissioned.
>
> Projections for 2016 and beyond are much less certain. The PTC has expired, and its renewal remains in question. Expectations for continued low natural gas prices, modest electricity demand growth, and limited near-term renewable energy demand from state RPS policies also put a damper on growth expectations, as do inadequate transmission infrastructure and growing competition from solar energy in certain regions of the country. Industry hopes

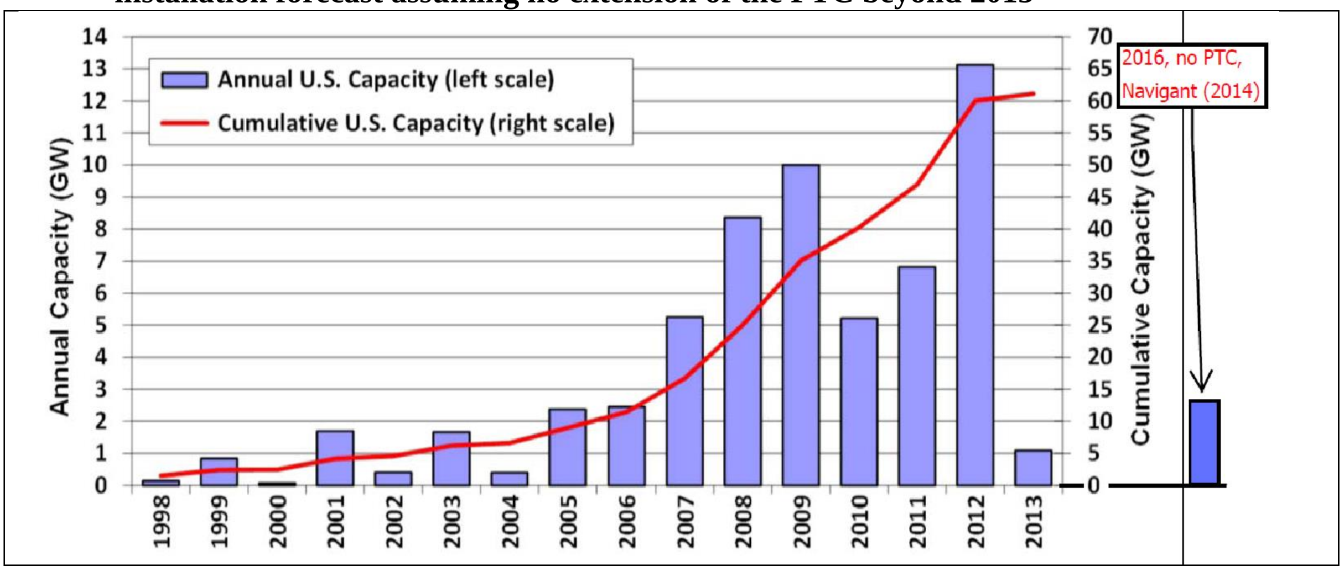
[78] Ex.-CETF/SOUL-Powers-14, p. 73.

for a federal renewable or clean energy standard, or climate legislation, have also dimmed in the near term.

Q. What are the growth prospects for the U.S. wind industry in 2016 if the Production Tax Credit (PTC) is not extended further?

A. Not good. Navigant Consulting, cited as a reference by DOE in its August 2014 assessment of the U.S. wind industry, projects total U.S. wind capacity additions in 2016 without a PTC of 2,800 MW.[79] The historic U.S. wind capacity installation trend is shown in Figure 2, along with the Navigant forecast of U.S. wind capacity additions in 2016 timeframe with no extension of the PTC beyond 2015.

Figure 2. Historic U.S. wind capacity installation trend and Navigant 2016 capacity installation forecast assuming no extension of the PTC beyond 2015[80]



Note: Text box and 2016 annual capacity bar added by B. Powers.

Q. Has the installation rate of U.S. and Midwest wind power dropped substantially in the last two years?

[79] *Id*. at 73.

[80] *Id*. at 3.

A. Yes. Figure 3 shows the sharp decline in U.S. wind capacity additions since the first quarter of 2013. Figure 4 shows the rate of wind capacity additions in Iowa and Minnesota in the 2011-2014 period.

Figure 3. Rate of addition of U.S. wind capacity declined precipitously in 2013-2014[81]

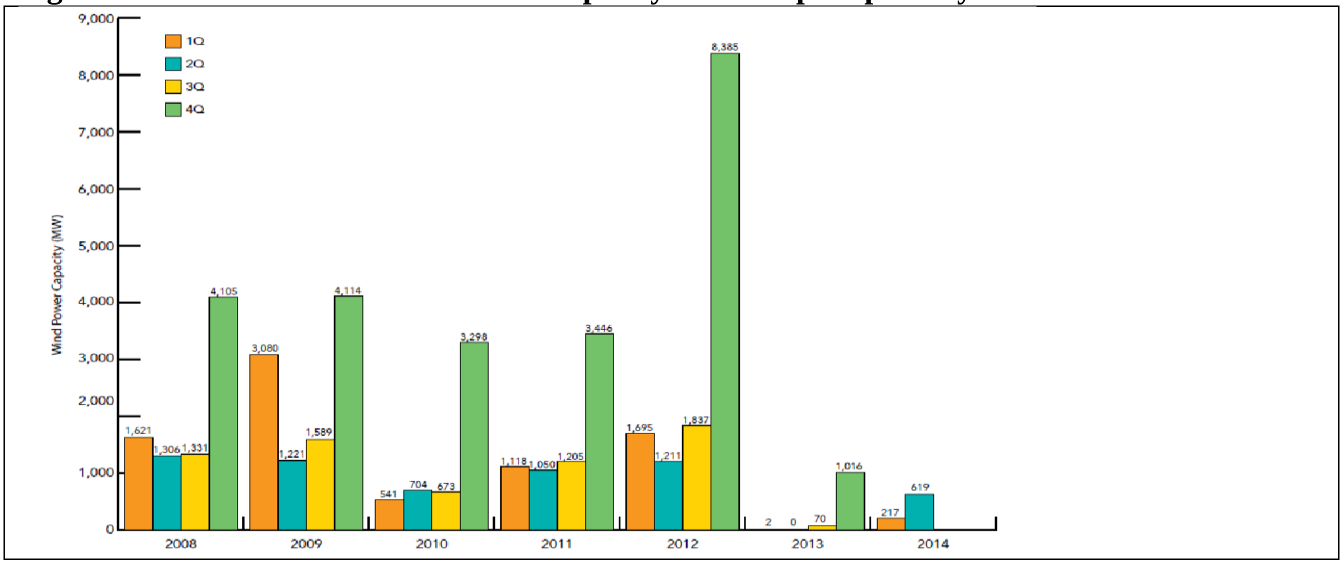
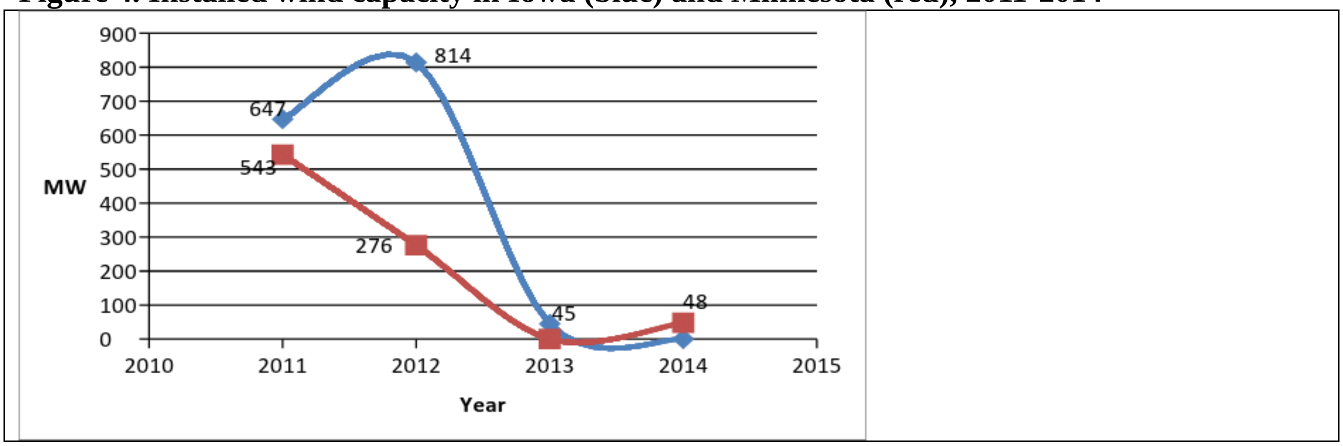


Figure 4. Installed wind capacity in Iowa (blue) and Minnesota (red), 2011-2014[82,83,84, 85]



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[81] Ex.-CETF/SOUL-Powers-15, p. 6.

[82] Ex.-CETF/SOUL-Powers-16.

[83] Ex.-CETF/SOUL-Powers-17.

[84] Ex.-CETF/SOUL-Powers-18.

[85] Ex.-CETF/SOUL-Powers-15.

Q. Have wind power installations declined in Iowa in the last two years?

A. Yes. The percentage of Iowa's electricity provided by wind in 2013 was 27.4 percent.[86] The installed wind capacity in Iowa through the end of 2013 was 5,177 MW. No wind capacity added in Iowa in the first two quarters of 2014.

Q. Have wind power additions in Minnesota been in decline since 2011?

A. The percentage of Minnesota's electricity provided by wind in 2013 was 15.7 percent.[87] The installed wind capacity in Minnesota through the end of 2013 was 2,987 MW. No new wind capacity was added in Minnesota in 2013. 48 MW of wind capacity was added in Minnesota in the first quarter of 2014.[88]

Q. Has limited near-term renewable energy demand from state RPS policies put a damper on wind power development?

A. Yes. DOE is correct in asserting that limited near-term renewable energy demand from state RPS policies puts a damper on wind power growth expectations. The DOE observation is accurate for Wisconsin, Iowa, and Minnesota. As shown in Table 12, Wisconsin and Iowa have met their RPS targets and Minnesota was more than two-thirds of the way in 2013 toward its 2025 RPS target of 25 percent.

Table 12. Current RPS levels, targets, and compliance dates in Wisconsin, Minnesota, and Iowa[89]

State	Current RPS level (%)	RPS target (%)	RPS compliance date
Wisconsin	10.8[90]	10	2015
1. Minnesota[91]	15.7	25	2025

[86] Ex.-CETF/SOUL-Powers-16.

[87] Ex.-CETF/SOUL-Powers-17.

[88] Ex.-CETF/SOUL-Powers-15, p. 7.

[89] Ex.-CETF/SOUL-Powers-19.

[90] PSC Ref. # 220557, p. 4.

[91] Ex.-CETF/SOUL-Powers-17.

2. Xcel (MN)		30	2020
Iowa[92]	27.4	105 MW	1999

XII. The Economic and Reliability Benefits of Solar Power Are Not Considered by the Applicants

Q. Does ATC compare the economic benefits of solar power to wind power in its application?

A. No. The ATC Planning Analysis does not consider solar as an economic option to wind power imports, despite the ability of solar power to compete effectively on economic terms with wind power. The Applicants assume a 2018 capital cost of wind power for the Limited Growth scenario of $2,688/kW.[93] In the Robust Economy scenario ATC forecasts s wind power capital cost of $3,360/kW.[94] In contrast, solar projects in the 10 MW capacity range are being built now for approximately $2,100/kW and solar costs are projected to continue to fall substantially in the near- and mid-term future. Unlike wind power, solar output is well matched to diurnal and summer peak load profiles of Wisconsin utilities. This attribute contributes to the much higher "grid value" of solar power, in the form of firm solar capacity available at summer peak demand, compared to wind power.

Q. What are current costs for solar power?

A. The DOE-modeled capital cost estimate for a 10 MW solar PV project in Q4 2013 was $1,930/kW$_{dc}$.[95] This is comparable to the $2,000/kW$_{ac}$ capital cost for four 10 MW solar

92 Ex.-CETF/SOUL-Powers-16.

93 The capital cost for wind capacity (in 2018 dollars) used in the Renewable Investment Benefit (RIB) calculation ranges from $2,688/kilowatt (kW) for slow growth to $3,360/kW for robust economy - Explain why the values used are reasonable considering the EIA cost estimates. ATC Response - The lower end of the range remains consistent with current EIA cost estimates and the upper end of the range remains representative of those futures where additional growth and expansion of wind development would put upwards pressure on capital costs.

94 *Id*.

95 Ex.-CETF/SOUL-Powers-20, p. 22.

PV projects in New Mexico announced in June 2014.[96,97] Solar PV contracts are being signed in 2014 at power purchase agreement (PPA) prices less than \$50/MWh.[98]

Q. What are solar prices projected by DOE for 2016?

A. Table 13 summarizes DOE capital cost projections for rooftop and utility-scale solar PV DOE forecasts that capital cost will decline to as low as \$1,300/kW_{dc} for systems 5 MW and up by 2016, as low as 1,500/kW_{dc} for rooftop systems by 2016.[99] Reported system prices of residential and commercial PV systems declined 6 to7 percent per year, on average, from 1998–2013, and by 12 to 15 percent from 2012–2013, depending on system size.[100] The 2016 forecast capital cost ranges shown in Table 13 are consistent with this historic solar PV price decline rate. [101]

Table 13. DOE current and projected capital costs for rooftop and utility-scale ($\geq$ 5 MW) solar PV projects[102]

Type of solar PV	2014 modeled capital cost (\$/kW_{dc})	2016 forecast best-case & mid-point capital cost (\$/kW_{dc})
Residential rooftop	3,290	1,500 – 2,250
Commercial rooftop	2,540	1,500 – 2,250
Utility-scale, 5 MW	2,030	1,300 – 1,625

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96 Ex.-CETF/SOUL-Powers-21; Ex.-CETF/SOUL-Powers-22.

97 Ex.-CETF/SOUL-Powers-23, p. 16. For utility-scale solar, the dc-to-ac conversion is assumed to be 90 percent. A \$1,930/kW_{dc} capital cost equals a kW_{ac} cost of: \$1,930/kW_{dc} ÷ 0.9 = \$2,144/kW_{ac}.

98 Ex.-CETF/SOUL-Powers-24.

99 Ex.-CETF/SOUL-Powers-20, pp. 27–28.

100 *Id*. at 4.

101 *Id*. at 24. Germany average residential PV installed price in 2013 was \$2.05/W_{dc}. Hardware costs are fairly similar between the U.S. and Germany. Therefore the gap in total installed prices must reflect differences in soft costs (including installer margins). The German residential PV system cost is reflective of a potential for near-term installed price reductions in the U.S.

102 *Id*. at 4, 22 (5 MW system at \$2.03/W).

Q. What is the 2016 capacity cost in $/kW-yr for 5 MW solar project in ATCW territory?A. DOE identifies the 2016 best-in-class to mid-range capital cost for utility-scale solar ≥ 5 MW of $1,300/kW_{dc}$ to $1,625/kW_{dc}$. The adjusted capital cost, based on alternating current (ac) output and assuming a dc-to-ac conversion efficiency of 90 percent, [103] would be $1,444/kW$_{ac}$ to 1,806/kW$_{ac}$, or $136.31/kW-yr to $170.49/kW-yr[104] The Energy Information Administration identifies a fixed O&M cost for solar projects of $27.75/kW-yr.[105] The total annual cost of the > 5 MW single-axis tracking solar project using these assumptions would be $164.06/kW-yr ($820,300/yr) to $198.24/kW-yr ($991,200/yr).[106]

The annual capacity factor of this system located in La Crosse, Wisconsin is 0.233.[107] At a capacity factor of 0.233,[108] a 5 MW single-axis tracking solar PV project will generate 10,205.4 MWh/yr.[109] Therefore, the best case break-even unsubsidized power purchase solar price in 2016 would be: $820,300/yr ÷ 10,205.4 MWh/yr = $80.4/MWh. The mid-range break-even unsubsidized power purchase solar price in 2016 would be: $991,200/yr ÷ 10,205.4 MWh/yr = $97.1/MWh.

The capacity factor of a single-axis tracking solar system during summer peak demand hours is 0.72.[110] As a result the cost of single-axis tracking solar PV as a capacity

[103] Ex.-CETF/SOUL-Powers-23, pp. 10, 16.

[104] At a finance rate of 7 percent interest over 20 years (0.0944/yr cost recovery factor), the annualized best-case capital cost of a 5 MW (5,000 kW) single-axis tracking solar project would be: $1,444/kW × 5,000 kW x 0.0944 = $681,568/yr. This equals a capacity cost of: $681,568/yr ÷ 5,000 kW = $136.31/kW-yr. The annualized mid-range capital cost $1,806/kW × 5,000 kW x 0.0944 = $852,432/yr. This equals a capacity cost of: $852,432/yr ÷ 5,000 kW = $170.49/kW-yr.

[105] Ex.-CETF/SOUL-Powers-14, p. 6.

[106] Best case: Annualized capital cost + annual O&M cost = $136.31/kW-yr + $27.75/kW-yr $164.06/kW-yr. Mid-range: $170.49/kW-yr + $27.75/kW-yr = $198.24/kW-yr.

[107] Ex.-CETF/SOUL-Powers-25.

[108] *Id.*

[109] 5 MW × 8,760 hr/yr × 0.233 = 10,205.4 MWh/yr.

[110] Ex.-CETF/SOUL-Powers-5, p. 4.

resource to offset the summer peak ranges from a best case of \$164.06/kW-yr ÷ 0.72 = \$227.86/kW-yr, to a mid-range of \$198.24/kW-yr ÷ 0.72 = \$275.33/kW-yr.[111]

Q. Is distributed solar already in operation along the proposed B-C route?

A. Yes. Distributed solar PV is already being installed along the proposed route of B-C. For example Dairyland Power Cooperative and Vernon Electric Cooperative (VEC) installed 822 kW (0.82 MW) of solar PV in 2014 in VEC's Westby, Wisconsin, headquarters of the cooperative.[112, 113] Westby is about 25 miles southeast of La Crosse. A photograph of one of these solar projects, the 305 kW Vernon Electric Community Solar Farm, is shown in Figure 5. This is an example of additions of clean power consistent with Wisconsin energy law that can address any incremental peak load increases that may occur on individual substations in the La Crosse/Winona area and reduce the greenhouse gas footprint of the grid power supply over time.

Figure 5. Vernon Electric Cooperative 305 kW Vernon Electric Community Solar Farm installed in 2014[114]

Q. If the DPC/Vernon Electric 2014 rate of solar addition continued year-to-year through 2023, and was actually occurring in the nearby La Crosse/Winona area, what impact would it have on the rate of peak load growth in that area?

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[111] \$198.24/kW-yr ÷ 0.72 = \$275.33/kW-yr.

[112] Ex.-CETF/SOUL-Powers-26.

[113] Ex.-CETF/SOUL-Powers-27.

[114] *Id*.

A. The reduction of the La Crosse/Winona area peak load of approximately 450 MW at a rate of 0.82 MW per year is equivalent to a peak load decline rate of -0.18 percent per year.[115]

Q. Has local solar been identified in Minnesota as a lower-cost alternative to new simple cycle gas turbine construction?

A. Yes. In Minnesota, Geronimo Energy filed a Distributed Solar Energy proposal with the Minnesota Public Utilities Commission in April 2013 to provide up to 100 MW_{ac} of solar power to meet a portion of Xcel Energy's capacity and energy needs between 2017 and 2019.[116] Geronimo proposed the construction and operation of these single-axis tracking solar PV projects, ranging from 2 to 10 MW, on up to 31 sites adjacent to substations located throughout Xcel Energy's Upper Midwest Service Territory.

Q. When did Minnesota make this solar determination?

A. The administrative law judge assigned to the Minnesota Public Utilities Commission proceeding determined in his proposed decision that the Geronimo Energy solar proposal was more cost-effective than the peaking gas turbine alternative in January 2014. The proposed decision states "On a per MWh basis, a solar unit is also the lowest cost stand-alone resource."[117] The proposed decision also noted that Geronimo the project will not produce greenhouse gas emissions of its own, and will avoid 94,133 tons of CO_2 emissions per year.[118]

The Minnesota Public Utilities Commission approved the Geronimo Energy project in March 2014.[119] The in-service date for the project is December 2016.[120] The solar

115 -0.82 MW ÷ 450 MW = -0.18 percent per year.

116 Ex.-CETF/SOUL-Powers-5.

117 Ex.-CETF/SOUL-Powers-28, p. 39.

118 *Id*. at 43.

119 Ex.-CETF/SOUL-Powers-29.

120 Ex.-CETF/SOUL-Powers-5.

capacity will be available to meet Xcel Energy’s peak demand for the summer season of 2017.[121]

Q. Will Minnesota be meeting its RPS targets with a mix of solar and wind resources in the near-term future?

A. Yes. Minnesota does have a remaining RPS gap to fill between now and 2025. Minnesota will clearly meet this gap with a mix of resources, including local solar. The 100 MW Geronimo solar project represents more capacity than the 48 MW of Minnesota wind power installed in 2013-2014 combined.

XIII. Job Growth and Economic Benefits to Wisconsin Are Greater with Local Clean Energy Solutions

Q. Have any recent studies been conducted in the region of the job growth and economic benefits of local clean energy alternatives?

A. Yes. Minnesota published an evaluation of the economic impact of the clean energy industry in the state in 2014. Minnesota and Wisconsin are comparable in geographic location, population, and electricity demand. The effect of the clean energy development on the Minnesota economy is summarized in the following manner:

> The state’s clean energy economy created nearly 7,000 jobs over the last 15 years, growing seven times faster than the state’s overall employment. Clean energy employment in Minnesota surged 78 percent between January 2000 and first quarter 2014, while the state’s total employment grew only 11 percent over the same period.

In 2014, approximately 70 percent of Minnesota clean energy jobs are in either the energy efficiency or smart grid sectors, with a total of 10,600 jobs. The number of jobs in the bioenergy, wind, and solar sectors in 2014 are comparable, with 1,800 jobs in

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[121] *Id.*

bioenergy, 1,700 jobs in wind, and 1,200 in solar. The report notes the enhanced economic benefit of energy efficiency and solar energy derived from the local focus of these two sectors, stating:

> Energy efficiency and solar energy sector companies in particular generate most of their revenues from within Minnesota, which is a reflection of common value chain functions in those sectors that are often based locally, such as installation and maintenance of energy systems or solar panels. The majority of companies in the wind power, bioenergy, and smart grid sectors reported that more than half of their revenue came from outside of Minnesota.

Q. Have the economic benefits of a local solar alternative been quantified?

A. Yes. A specific example of the economic benefit of a solar project in Minnesota was provided in the proposed decision recommending approval of the 100 MW Geronimo project:[122]

> Geronimo's proposal will produce numerous socioeconomic benefits. In particular, the construction phase of Geronimo's project will include approximately 500 jobs, dispersed in work crews of between 13 and 40 members each. Further, operation and maintenance of its power generation facilities will require up to 10 permanent positions.

Q. Will importing wind power over the proposed B-C transmission line generate clean energy economic activity in Wisconsin?

A. No. Local clean energy economic activity will not be generated in Wisconsin by the construction of B-C. In fact, a primary justification for B-C is importing clean energy from out-of-state. This imported clean energy, to the extent that it is used in Wisconsin, will displace the economic activity that would otherwise have occurred in Wisconsin to provide that clean energy.

[122] Ex.-CETF/SOUL-Powers-28, p. 42.

XIV. No-Wires Alternatives Are Lower-Cost Solutions to Modeled LV Segment 2023 NERC Violations

Q. What is the comparative cost of no-wires alternatives to the B-C LV alternative?

A. The comparative cost of three no-wires alternatives to B-C are provided in in Tables A-1 and A-2 in Ex.-CETF/SOUL-Powers-35. Table A-1 compares the cost of the LV alternative analyzed by B-C to cost of three no-wires alternatives, LM (LM), energy efficiency (EE), and solar PV (PV), assuming the no-wires alternatives are off-setting an annual peak load growth of 0.22 percent per year. Table A-2 shows the same comparison for the non-ATC LV segments. Table 14 summarizes the comparative cost data presented in Tables A-1 and A-2.

Table 14. Cost of 2023 basecase LV alternative compared to three no-wires alternatives to address 0.22 percent peak load growth

LV Category	ATC 2023 Basecase		0.22 percent per year Limited Growth Scenario			
	Total NERC violations (MVA)	ATC upgrade cost ($ millions)	Total NERC violations (MVA)	LM upgrade cost ($ millions)	EE upgrade cost ($ millions)	PV upgrade cost ($ millions)
ATV LV Segments (16)	148.7	92.6	30.9	1.04	2.79	5.46
Non-ATV LV Segments (13)	201.1	98.3	58.3	2.33	6.66	13.29
Total:	349.8	190.9	89.2	3.37	9.45	18.75

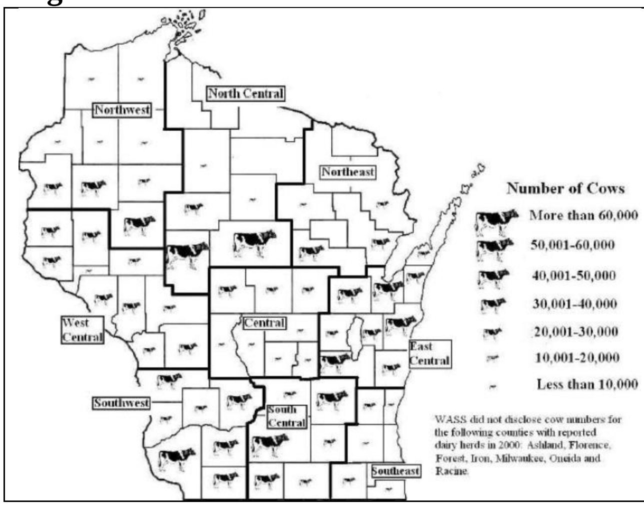
The cost of the no-wires alternatives to offset the 0.22 percent per year peak load growth scenario, at $3.37 million (LM), $9.45 million (energy efficiency), and $18.75 million (solar), are a fraction of the $190.9 million identified by ATC to upgrade LV segments as an alternative to B-C.

XV. Generation Potential of Dairy Digesters

Q. Are dairy digesters a potential source of local generation that could serve to offset demand for grid power?

A. Yes. Wisconsin is fifth in the nation in terms of dairy farm capability to generate biogas, with a potential of 386,000 MWh/year.[123] This is equivalent to a continuous output of 44 MW.[124] There is a high concentration of dairies in southwest Wisconsin along the proposed route of B-C, as shown in Figure 6. Dairy digesters do have the potential to contribute to further lowering the peak demand trend in southwest Wisconsin.

Figure 6. Distribution of dairies in Wisconsin[125]



XVI. Battery Storage

Q. What form of energy storage is in widespread use in Wisconsin?

A. Hot rock thermal storage is the form of energy storage in widespread use in Wisconsin.

Q. Are battery systems a cost-competitive for meeting peak load and other grid reliability functions?

A. Battery storage is another alternative that is cost-competitive with new conventional gas turbines used to provide peaking power.[126] This is in part due to the limited utilization of

[123] Ex.-CETF/SOUL-Powers-30. *See* http://www.epa.gov/agstar/documents/Market_Opps_Fact_Sheet.pdf.

[124] 386,000 MWh/year ÷ 8,760 hr/yr = 44.06 MW.

[125] Ex.-CETF/SOUL-Powers-32, p. 4.

a peaking gas turbine compared with energy storage. Compared to a new simple cycle gas turbine, which may be utilized at an annual capacity factor of 10 percent or less, the multiple uses of battery storage allow for approximately 95 percent utilization. In addition to peak demand capacity, other services such as regulation and spinning reserves can be provided by battery storage all year. Energy storage also has superior response time compared to a conventional simple cycle gas turbine. Storage requires less than a second to ramp to full capacity, is flexible throughout its entire range, and by taking in energy and then discharging it, has twice the ramping range as its nameplate capacity.

XVII. Environmental Advantages of No Wires Alternatives

Q. The B-C DEIS states, ". . . construction and operation of the proposed Badger Coulee 345 kV transmission line would have substantial impacts on many natural, community and cultural resources in the project area, regardless of what alternatives are chosen." How would the use of no-wires alternatives compare to the proposed B-C transmission line regarding such impacts?

A. Energy efficiency measures would have no environmental impacts. Rooftop solar would have no significant air, water, or land impacts. The environmental advantages of rooftop solar relative to remote utility-scale renewable energy and associated transmission lines were recognized by the California Public Utilities Commission at the time of its approval of a 500 MW urban warehouse rooftop PV project:[127]

Added Commissioner John A. Bohn, author of the decision, "This decision is a major step forward in diversifying the mix of renewable resources in California and spurring the development of a new market niche for large scale rooftop solar applications. Unlike other generation resources, these projects can get built quickly and without the need for expensive new transmission lines. And since they are built on existing structures, these projects are extremely benign from an environmental standpoint, with neither land use,

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[126] Ex.-CETF/SOUL-Powers-31, pp. 11–16.

[127] Ex.-CETF/SOUL-Powers-33.

water, or air emission impacts. By authorizing both utility-owned and private development of these projects we hope to get the best from both types of ownership structures, promoting competition as well as fostering the rapid development of this nascent market."

Q. What are the forecast CO_2 emissions from B-C compared to CO_2 emissions from energy measures and local solar?

A. The rate of increase of CO_2 emissions from the Wisconsin power sector is about 1 percent per year in the Slow Growth scenario with or without B-C.[128,129] The presence of B-C makes no significant difference in the rate of CO_2 emissions growth. The rate of CO2 emissions rise is substantially higher in the Green Economy and Robust Economy scenarios, about 2.4 and 3.0 percent per year through 2026.

Q. How does this compare with the impact of energy efficiency measures on CO_2 emissions?

A. At an energy efficiency savings rate of 0.7 percent per year, Wisconsin CO_2 emissions are reduced by approximately 581,000 tons per year.[130]

Q. How does this compare with the impact of local solar on CO_2 emissions?

A. FoE estimates that the conventional power generation mix supplying Wisconsin generates approximately 1,660 pounds of CO per MWh.[131] The displacement of this grid power mix with local solar eliminates these CO_2 emissions. The 100 MW Geronimo solar

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[128] Ex.-CETF/SOUL-Powers-34. Wisconsin net generation CO_2 emissions, 2012 = [63,742,910 MWh x (1,422 lb CO_2/MWh)(1 ton/2000 lb)] = 45,321,209 tons per year (tpy).

[129] (PSC Ref # 226511), p. 2, Response No. 1.03 (citing PSC Ref. # 197507). Slow Growth with B-C 2026 = 51,906,829 tpy. Slow Growth without B-C 2026 = 52,149,214 tpy. Percent per year increase in CO_2 with B-C = 1.01 percent per year. Percent per year increase in CO_2 without B-C = 1.02 percent per year.

[130] Ex.-CETF/SOUL-Powers-4. Assume 100,000 MWh reduction per 0.1 percent energy efficiency savings. Therefore, CO_2 avoided by 0.7 percent per year energy efficiency savings = 7 × [(100,000 MWh) × 0.83 tons CO_2/MWh] = 581,000 tons/yr CO_2.

[131] *Id*. CO_2 content of grid power = 0.83 tons per MWh (1,660 pounds CO_2 per MWh).

project in Minnesota will eliminate 94,133 tons per year of CO_2 emissions that would otherwise be emitted by conventional power generators to meet the same need.[132]

XVIII. Conclusion

Q. Does this conclude your testimony?

A. Yes.

[132] Ex.-CETF/SOUL-Powers-28, p. 43.